**BEFORE THE**
**PUBLIC SERVICE COMMISSION OF**
**SOUTH CAROLINA**
**DOCKET NO. 2013-3-E**

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| In the Matter of<br>Annual Review of Base Rates<br>for Fuel Costs for<br>Duke Energy Carolinas, LLC | )<br>)<br>)<br>) | **DIRECT TESTIMONY OF**<br>**JOSEPH A. MILLER, JR. FOR**<br>**DUKE ENERGY CAROLINAS, LLC** |

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Joseph A. Miller, Jr. and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am currently General Manager of Strategic Engineering for Duke Energy Business Services, LLC ("DEBS"). DEBS is a service company subsidiary of Duke Energy Corporation ("Duke Energy"), which provides services to Duke Energy and its subsidiaries, including Duke Energy Carolinas, LLC ("Duke Energy Carolinas", "DEC" or "the Company").

**Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.**

A. I graduated from Purdue University with a Bachelor of Science degree in mechanical engineering. I also completed twelve post graduate level courses in Business Administration at Indiana State University. My career began with Duke Energy (d/b/a Public Service of Indiana) in 1991 as a staff engineer at Duke Energy Indiana's Cayuga Steam Station. Since that time, I have held various roles of increasing responsibility in the generation engineering, maintenance, and operations areas, including the role of station manager, first at Duke Energy Kentucky's East Bend Steam Station, followed by Duke Energy Ohio's Zimmer Steam Station. I was named General Manager of Analytical and Investments Engineering in 2010, and was named to my current role following the merger between Duke Energy and Progress Energy, Inc.

**Q. WHAT ARE YOUR DUTIES AS GENERAL MANAGER OF STRATEGIC ENGINEERING?**

A. My responsibilities include environmental compliance planning and strategy, fuel flexibility, assessment of new technology developments, and analysis of plant retirements and new fossil generation for Duke Energy's fleet of fossil, and hydroelectric ("hydro" and collectively, "fossil/hydro") facilities.

**Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?**

A. Yes. I testified before this Commission in DEC's 2012 annual fuel proceeding in Docket No. 2012-3-E ("2012 Fuel Filing"), as well as in Duke Energy Progress, Inc.'s annual fuel proceeding earlier this year in Docket No. 2013-1-E. I also have filed testimony and testified in DEC's recent base rate adjustment hearing before this Commission in Docket No 2013-59-E.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to (1) describe DEC's generation portfolio and changes made since the 2012 Fuel Filing, as well as those expected in the near term, (2) discuss the performance of DEC's fossil/hydro facilities during the June 1, 2012 through May 31, 2013 review period (the "review period"), and (3) provide information on significant outages that occurred during the review period.

**Q. PLEASE DESCRIBE DEC'S FOSSIL/HYDRO GENERATION PORTFOLIO.**

A. The Company's fossil/hydro generation portfolio as of April 1, 2013 consists of approximately 14,400 megawatts ("MWs") of generating capacity, made up as follows:

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| Coal-fired - | 7,172 MWs |
| Hydro - | 3,229 MWs |
| Combustion Turbines - | 2,769 MWs |
| Combined Cycle Turbines - | 1,240 MWs |

The coal-fired assets consist of five generating stations and a total of 16 units. The Company has 13 units providing approximately 6,802 MWs of capacity that are equipped with emission control equipment, including selective catalytic or selective non-catalytic reduction ("SCR" or "SNCR") equipment for removing nitrogen oxides ("NOx"), and flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("$SO_2$"). In addition, all 16 coal-fired units are equipped with low NOx burners.

The Company has a total of 31 simple cycle combustion turbine ("CT") units, of which 29 are considered the larger group providing approximately 2,687 MWs of capacity. These 29 units are located at Lincoln, Mill Creek and Rockingham Stations, and are equipped with water injection systems that reduce NOx and/or have low NOx burner equipment in use. The Lee CT facility includes two units with a total capacity of 82 MWs equipped with fast-start ability in support of DEC's Oconee Nuclear Station. The 1,240 MWs shown earlier as "combined

cycle turbines" ("CC") represent the Buck CC and Dan River CC facilities that began commercial operation in late 2011 and late 2012, respectively. These facilities are equipped with the latest technology for emission control including SCRs, low NOx burners, and carbon monoxide/volatile organic compounds catalysts. The Company's hydro fleet includes two pumped storage hydro facilities with four units each that provide a total capacity of 2,140 MWs along with conventional hydro assets consisting of 75 units providing approximately 1,089 MWs of capacity.

**Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO PORTFOLIO SINCE DEC'S 2012 FUEL FILING?**

A. Changes within the portfolio include the addition of 1,445 MWs of new generation when Dan River CC and Cliffside Steam Station ("Cliffside") Unit 6 were declared available for commercial operation in December 2012. Additionally, DEC retired the remaining two units at Buck, Units 5 and 6 (256 MWs), along with Riverbend Steam Station, Units 4 through 7 (454 MWs) on April 1, 2013. These assets served customers well for multiple decades and, at 58 to 60 years old, were at the end of their useful lives. The Company had planned to operate these units until retirement in April 2015, but operated them infrequently in recent years and would operate them even less due to low natural gas prices and new generation resources that are more efficient. Additionally, DEC had already agreed to retire these units in progressive fashion under the Cliffside Unit 6 air permit and merger agreements. Lastly, due to age and obsolescence, DEC retired older CTs at Buck, Buzzard Roost, Dan River, and Riverbend Stations for a reduction of 350 MWs.

**Q. ARE OTHER CAPACITY CHANGES EXPECTED WITHIN THE FOSSIL/HYDRO PORTFOLIO FOR THE NEAR FUTURE?**

A. Not in the near term. However, DEC is finalizing analysis for the option of a gas conversion on unit 3 at the Lee Steam Station and will be submitting information to the Commission later this year or early in 2014.

**Q. WHAT ARE DEC'S OBJECTIVES IN THE OPERATION OF ITS FOSSIL/HYDRO FACILITIES?**

A. The primary objective of DEC's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEC's customers. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with procedures, guidelines, and a standard operating model.

Like safety, environmental compliance is a "first principle" and DEC works very hard to achieve high level results. The Company achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers. Equipment inspection and maintenance outages are scheduled during the spring and fall months when electricity demand is reduced due to weather conditions. These outages are well-planned and executed with the primary purpose of preparing the unit for reliable operation until the next planned

outage.

**Q. WHAT HAS BEEN THE HEAT RATE OF DEC'S COAL UNITS DURING THE REVIEW PERIOD?**

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy. Over the review period, the average heat rate for DEC's coal fleet was 9,480 Btu/kWh. The Company's largest units – those with the highest usage rates – achieved an average heat rate of 9,434 Btu/kWh for the review period. In operating performance data for 2011, published in the December 2012 issue of *Electric Light and Power* magazine, DEC's Belews Creek Steam Station ("Belews Creek") and Marshall Steam Station ("Marshall") ranked as the country's fourth and eighth most energy efficient coal-fired generators, with heat rates of 9,210 and 9,480 Btu/kWh, respectively. These results compare favorably to the average heat rate of 10,450 Btu/kWh for the North American coal generators. For the review period, the Belews Creek units provided the majority (45.7%) of coal-fired generation for DEC, with the Marshall units providing the second highest percentage (31.0%).

**Q. HOW MUCH GENERATION DID EACH TYPE OF GENERATING FACILITY PROVIDE FOR THE PERIOD?**

A. The Company's system generation totaled 95,749,846 MW hours ("MWHs") for the review period. The fossil/hydro fleet provided 38,103,878 MWHs, or approximately 40% of the total generation. The breakdown includes a 31% contribution from the

coal-fired stations, approximately 1% contribution each for the CTs and hydro facilities, and approximately 7% from the CC operations.

**Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR DEC'S FOSSIL/HYDRO FLEET DURING THE REVIEW PERIOD.**

A. The Company's generating units operated efficiently and reliably during the review period. The Company uses key measures to evaluate the operational performance of generating facilities: (1) equivalent availability factor; and (2) capacity factor. Equivalent availability factor refers to the percent of a given time period a facility was available to operate at full power, if needed. Equivalent availability is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (*i.e.*, forced) outage time. Capacity factor measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity. Capacity factor is affected by the dispatch of the unit to serve customer needs.

The performance metrics reported for the review period reflect a shift in operational characteristics and less than a full year of operational data for the new and retired facilities as noted previously in my testimony. Additionally, DEC is dispatching natural gas units more frequently to take advantage of low prices as described in Company witness Weintraub's testimony. The Company is therefore not only reporting the metrics on a total generator type basis, but is also reporting the metrics for the large coal-fired facilities, which have a higher usage rate and are the most cost effective generators within the generator type group.

The Company's larger coal-fired units achieved results of 87.0% equivalent availability factor and 51.6% capacity factor over the review period. During the 2012 peak summer season (e.g., June through August 2012), these larger units achieved results of 96.2% equivalent availability factor and 65.5% capacity factor. On a total coal-fired fleet basis, the capacity factor was 45.8% for the review period and 57.3% during the 2012 summer peak months. Overall, the coal-fired units achieved a fleet-wide availability factor of 88.4% for the review period, and 96.5% during the 2012 summer peak months. These results compare favorably with the most recently published North American Electric Reliability Council ("NERC") average equivalent availability results for all North American coal plants of 83.5%. The results, included in the NERC Generating Availability Report[1] ("NERC Report"), represent the period 2007 through 2011.

The Company's CTs located at Lincoln, Mill Creek, Rockingham, and Lee Stations were available as needed in this time period, with a 99.2% starting reliability, outperforming the average of 97.4% reported by NERC in the above-referenced report. The Buck and Dan River CC facilities reported a capacity factor of 79.2%, which is above the NERC reported average of 40.4%. With an overall availability factor of 90.9%, the hydroelectric fleet had outstanding operational performance during the review period, and also exceeded the NERC reported average availability factor of 85.2%.

[1] Typically, the Company obtains this data from NERC's Generating Unit Statistical Brochure ("NERC Brochure"). The most recent NERC Brochure, however, has not yet been published, and as a result, the Company computed this data from the NERC Report.

**Q. PLEASE DISCUSS SIGNIFICANT OUTAGES OCCURRING AT DEC'S FOSSIL/HYDRO FACILITIES DURING THE REVIEW PERIOD.**

A. In general, planned maintenance outages for all fossil and larger hydro units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. Most of these units had at least one small planned outage during this review period to inspect and maintain plant equipment. The following coal-fired units had planned outages of six weeks or more. In the fall of 2012, Allen Units 1, 2 and 5 had outages for FGD absorber maintenance and warranty work along with air preheater basket replacement for Unit 5. Significant work during these outages included installation of a potential adjustment protection system for the absorber reaction tank, battery bank replacement, and the rebuild of multiple valves. Marshall Unit 3 began a maintenance outage in the spring of 2013 which included turbine inspections. The inspections revealed cracking in some blade rows prompting an inspection on Unit 4 since that unit had the same blade design and relatively the same operational hours. The inspection verified that Unit 4 had the same cracking and required blade replacements as well. The Unit 3 return to service was delayed due notably to welding issues on the superheat outlet header.

Combustion turbine outages included Mill Creek Units 1 and 2 in the fall of 2012 to perform generator shaft seal and jacking oil replacements. Also in the fall, outages occurred for Lincoln Units 3 and 4 that involved generator inspections along with annual maintenance activities. Units 7 and 8 at Lincoln had spring 2013 outages for planned maintenance activities.

Outages began for Rockingham Units 1 and 3 for borescope inspections. The inspections revealed cracks and material loss in transition pieces with downstream damage to turbine blades and vanes. The Company opted to take Units 2 and 4, which are equipped with the same style and vintage pieces, offline and perform borescope inspections. The inspections on Units 2 and 4 revealed suspect areas in the transition pieces for Unit 2 and several cracked transition pieces but without material loss for Unit 4. Purchase of new components -- Units 1 and 3 had sustained in-service damage to certain components that were not repairable -- reduced the lead-time on repairs, and the units were returned to service late in December 2012. The components for Units 2 and 4 were repairable, which reduces the costs but increases the lead-time. Unit 4 returned to service in late May 2013, and Unit 2 will return pending a boroscope inspection.

Hydro outages included Cowans Ford Unit 2, which came back on-line from a planned outage in May 2013 following draft tube liner repairs. Great Falls Unit 2 was brought back on-line in early June 2013 following major repair to the exciter, transmitter, runner and turbine. Also, Lookout Unit 2 returned to service in April 2013 following a scheduled reduction involving a mechanical overhaul.

**Q. HOW DOES DEC ENSURE EMISSION REDUCTIONS FOR ENVIRONMENTAL COMPLIANCE?**

A. As noted above, DEC has installed pollution control equipment on coal-fired units, as well as new generation resources in order to meet various current federal, state, and local reduction requirements for $NO_x$ and $SO_2$ emissions. The SCR technology that DEC currently operates uses ammonia or, in the case of Marshall Unit 3, urea,

which is converted to ammonia for $NO_x$ removal. The SNCR technology injects urea into the boiler for $NO_x$ removal and the scrubber technology employed by DEC uses crushed limestone for $SO_2$ removal. Dibasic acid can also be used with the scrubber technology for additional $SO_2$ removal, and the reagents magnesium hydroxide and calcium carbonate are used for sulfur trioxide ("$SO_3$") mitigation. SCR equipment is also an integral part of the design of the Buck and Dan River CC Stations. Aqueous ammonia (19% solution of $NH_3$) is introduced for $NO_x$ removal.

Overall, the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emission reduction required. The Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. The goal is to effectively comply with emission regulations and provide the most efficient total-cost solution for operation of the unit.

**Q. DOES THAT CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes, it does.